APAD-1105

CATALYTIC

BIBLIOGRAPHIC DATA SHEET	1. Report No. APTD-1103	2.	PB 208 944

4. Title and Subtitle
Applicability Study - Coal Gasification Process

5. Report Date
March 1972

6.

7. Author(s)
L. K. Jain, T. J. Hixson

8. Performing Organization Rept. No. 41937

9. Performing Organization Name and Address
CATALYTIC, INC.
1515 Mockingbird Lane
Charlotte, North Carolina 28209

10. Project/Task/Work Unit No. No. 8

11. Contract/Grant No. 68-02-0241

12. Sponsoring Organization Name and Address
ENVIRONMENTAL PROTECTION AGENCY
Office of Air Programs, Division of Control Systems
Research Triangle Park, North Carolina 27711

13. Type of Report & Period Covered

14.

15. Supplementary Notes

16. Abstracts

The objective was to determine the applicability of a commercial coal gasification process to electric utility and industrial boiler facilities for new installations and for the "retrofit" of existing installations. Specific objectives are evaluation of the process with respect to cost, space limitations and operational, maintenance and safety aspects. In addition, a number of technical difficulties and unresolved problems are outlined. The use of the coal gasification process may offer potential capital cost savings, compared to existing methods of sulfur removal in the combustion of coal, markets for caking-type high sulfur coals (10,000 BTU/Lb. or less) and a method of reducing particulate emissions by converting coal to a cleaner fuel.

17. Key Words and Document Analysis. 17a. Descriptors

Air pollution control equipment
Coal gasification
Boilers
Expenses
Maintenance
Safety equipment
Particles

17b. Identifiers/Open-Ended Terms

Reproduced by
NATIONAL TECHNICAL
INFORMATION SERVICE
Springfield, Va. 22151

17c. COSATI Field/Group 13B

18. Availability Statement	19. Security Class (This Report)	21. No. of Pages
Unlimited	UNCLASSIFIED	26
	20. Security Class (This Page) UNCLASSIFIED	22. Price

1103

APPLICABILITY STUDY

COAL GASIFICATION PROCESS

FINAL REPORT

APPLICABILITY STUDY
COAL GASIFICATION PROCESS

CONTRACT NO. 68-02-0241

ENVIRONMENTAL PROTECTION AGENCY

MARCH 1972

EPA CONTRACT NO. 68-02-0241 - TASK NO. 8

CATALYTIC PROJECT NO. 41937

BY

L. K. JAIN
T. J. HIXSON

MARCH 1972

PREPARED BY

CATALYTIC, INC.
1515 MOCKINGBIRD LANE
CHARLOTTE, NORTH CAROLINA 28209

PREPARED FOR

DIVISION OF CONTROL SYSTEMS
OFFICE OF AIR PROGRAMS
ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK
NORTH CAROLINA

ACKNOWLEDGEMENTS

Many individuals and several organizations have been helpful in developing this study; for these contributions Catalytic, Inc. extends its sincere gratitude. The following individuals deserve particular credit for their contributions:

Applied Technology Corporation	-	Mr. J. Karnavas
	-	Mr. P. LaRosa
Alleghany Power Company	-	Mr. W. Kress
	-	Mr. H. Micala
Babcock and Wilcox Company	-	Mr. D. O'Brien
Carolina Power and Light Company	-	Mr. J. Sell
Duke Power Company	-	Mr. D. Voyles
National Academy of Science	-	Mr. R. Crozier
Office of Coal Research	-	Mr. N. Cochran
Tennessee Valley Authority	-	Mr. R. Haskins
	-	Mr. U. Zitzon
Getty Oil Company	-	Mr. C. Phillips
Delmarva Power Company	-	Mr. H. Hoen

TABLE OF CONTENTS

Page

INTRODUCTION.....1

DESCRIPTION OF PROCESS.....1

DISCUSSION.....2

Introduction.....2

Cost Aspects.....3

Space Requirement for the Process.....4

Type of Fuel.....6

Operational, Maintenance and Safety Aspects.....7

By-Product Disposal.....7

Standby Fuel Requirements.....8

Turndown Capabilities of the Combustion.....8

Safety Aspects of the Process.....8

Scheduled Maintenance and "Down-Time".....10

Design Problems.....10

APPENDIX A. CONCEPTUAL DESIGN OF COMBUSTOR.....13

APPENDIX B. ATC COAL COMBUSTION PROCESS.....14

APPENDIX C. ESTIMATED COST FOR COMBUSTION PROCESS.....15

APPENDIX D. CAPITAL COSTS FOR COAL GASIFICATION/SULFUR REMOVAL PROCESSES.....16

APPENDIX E. ATC PROCESS INSTALLED CAPACITY VS. CAPITAL COSTS.....17

APPENDIX F. ATC PROCESS INSTALLED CAPACITY VS. COST/KW....18

APPENDIX G. EXISTING AND PLANNED POWER GENERATING FACILITIES.....19

REFERENCES.....20

INTRODUCTION

The Environmental Protection Agency has the task of developing technology for a national program for control of air pollution. One aspect of this program is advancement of technology in the boiler industry so that emission control and compliance with state and federal regulations can be met with a minimum expenditure of time and money.

The objective of this study is to determine the applicability of the Applied Technology Corporation (ATC) Coal Gasification Process to electric utility and industrial boiler facilities for new installations and for the "retrofit" of existing installations. Specific objectives are evaluation of the process with respect to cost, space limitations and operational, maintenance and safety aspects. In addition, a number of technical difficulties and unresolved problems are outlined.

The use of the ~~ATC~~ Coal Gasification Process may offer potential capital cost savings, compared to existing methods of sulfur removal in the combustion of coal, markets for caking-type high sulfur coals (10,000 BTU/Lb. or less) and a method of reducing particulate emissions by converting coal to a cleaner fuel.

DESCRIPTION OF PROCESS

The process under study consists basically of a cylindrical-shaped, refractory-lined metal structure, termed a combustor (Appendix A), to convert pulverized coal into a "low BTU" fuel gas. The combustor contains a mass of molten iron into which the crushed coal is pneumatically injected by means of a lance.

DESCRIPTION OF PROCESS (Continued)

Upon entering the bath, volatile components in the coal are separated from soluble portions, chiefly consisting of carbon (relatively low solubility) and sulfur (relatively high affinity for iron). The high affinity of sulfur for iron prevents formation of significant amounts of sulfur dioxide. The dissolved carbon is oxidized to carbon monoxide by means of air injection through an additional lance, while dissolved sulfur is extracted by continuous injection and removal of a limestone/slag mixture. Iron is a by-product of the process through decomposition of pyritic sulfur compounds present in the coal.

The prime product is a high temperature (2500°F - 2700°F) gas rich in carbon monoxide and hydrogen, with approximately 175 BTU/Std. Cu. Ft. available heat of combustion. Preliminary data indicates that negligible amounts of particulate matter are found in the off-gas. The sulfur-containing slag is treated by a Claus process to produce elemental sulfur as a product (Appendix B).

DISCUSSION

Introduction

The subject process was studied based on data supplied by Applied Technology Corporation and discussions with various firms having a direct interest in the process, including utility companies, boiler manufacturers and related industries. Conclusions developed during this study are based only on preliminary technical and cost information without actual pilot tests and are subject to this qualification.

DISCUSSION (Continued)

Cost Aspects

Preliminary fixed capital cost requirements incorporating this process in a 1,000 megawatt new power installation are $23,330,000 (1) (1980 basis - Appendix C). This cost relates favorably to costs of comparable processes under consideration for 1,000 megawatt power plants (2) (Appendix D). Scaled-down costs for the ATC process for new installations smaller than 1,000 megawatts were developed from the base data and application of a 0.6 power scale factor (Appendix E). A graphical relation of capital cost per kilowatt versus size of installation indicates a significant increase in unit cost as the size of the installation is decreased below 300 megawatts (Appendix F). Since existing flue gas desulfurization processes are available at approximately $40/KW (3), the indicated minimum size, economically attractive installation for the ATC process, is 250 megawatts. This conclusion eliminates economic application of the ATC process in all industrial applications and 55 percent of existing coal-fired steam electric plants.

The process theoretically is economically feasible for "retrofit" plants in 45 percent of the existing (1971) steam electric units (188 of 419, representing 83 percent of present, installed capacity of coal burning units) and 100 percent of the planned (1971-1980) new plants (91 units) of 240 megawatts size or greater (4) (Appendix G).

Additional possible favorable cost aspects which apply to use of the ATC process in new facilities are:

DISCUSSION (Continued)

Cost Aspects (Continued)

1. Cost savings by the total or partial elimination of pulverizers, since the process has capabilities of handling up to 200 mesh - 1/4" coal.
2. Cost savings by the use of shorter boiler exhaust stacks, since the emission of sulfur dioxide is minimal.
3. Cost savings by the installation of smaller size boilers for the combustion of the gasified coal, assuming no standby fuel requirements.
4. Possible cost savings from elimination of particulate emission equipment.

Until proven that the process is economical and the potential cost saving aspects are favorable, the users indicate that the process is seemingly feasible for 250 MW or larger new boilers.

Because of the comparative individuality with respect to boiler design and plant layout of existing coal-fired steam electric plants, it is not possible to assess rigorously the capital costs required for retrofitting the process to an existing installation without in-depth engineering studies of each facility. Similarly, the factors affecting costs concerning the chronological age of the existing boilers are sufficiently diverse for different boilers that a specific age limitation was not indicated by the potential users.

Space Requirement for the Process

A 1,000 megawatt electric utility plant, using the ATC process as a fuel source, will require typically three combustors, each

DISCUSSION (Continued)

Space Requirement for the Process (Continued)

approximately 38' in diameter. The combustors will operate continuously with one combustor serving as a spare.

Scaledown for smaller size installations is a function of installation capacity, coal solubility rate and off-gas velocity. The limiting factors in determing a minimum practical combustor size are heat loss per pound of coal converted and area for stabilizing reaction turbulence. Both heat loss and reactor turbulence increase proportionately with decrease in combustor diameter. No effort is made at this time to determine quantitatively the practical minimum combustor diameter. The ATC bench-scale application is approximately 3' in diameter.

Suggested possible locations for the combustor installation with respect to the boilers in a "retrofit" plant are:

1. In place of existing pulverizers, assuming discontinuation of the pulverizing requirement.
2. On the opposite side of the steam boilers from the pulverizers, if the pulverizers are required.
3. In between two boilers.
4. In a remote area within 100' of the boilers (probably outside building at grade level).
5. In place of existing electrostatic precipitators or equivalent particulate control devices, assuming no particulate emission problems for commercial units.

From a random sampling of power industry personnel, it appears

DISCUSSION (Continued)

Type of Fuel (Continued)

limits and a developed sulfur market. According to 1971 data[5], 39,000 tons per day of petroleum coke are generated in the United States, capable of producing 5,000 megawatts of power. Potential application of the ATC process to converting petroleum coke contributes to its attractiveness.

Operational, Maintenance and Safety Aspects

By-Products Disposal

The three by-products produced by the ATC process are elemental sulfur, desulfurized slag and granulated iron. In the cases of sulfur and iron, the chief factors affecting disposal are market price and location. No significant disposal problems are foreseen at this time. However, no credit in the developed economic data is taken relative to these marketable by-products.

The slag exhibits good road construction properties. However, due to increased quantity compared to fly ash quantity from a conventional coal burning station, some additional disposal expenditures for slag will be required. It is apparent that sulfur-laden slag will not be an acceptable landfill material over a long period of time, because of the potential release of hydrogen sulfide through hydrolysis.

The by-product slag from the combustor will be 30 percent higher in weight than equivalent fly ash and will have much higher bulk density. Additionally, it is possible that transportation of slag as a slurry will be more difficult than cur-

DISCUSSION (Continued)

Operational, Maintenance and Safety Aspects (Continued)

By-Products Disposal (Continued)

rent means of pumping fly ash slurries. Hence, it is possible that the by-products will require an increased material handling expenditure over current conventional plants. The possible increase in material handling cost is not included in the cost estimate (Appendix C).

Standby Fuel Requirements

Standby fuel is not required if an application which uses a minimum of two combustors, with one acting as spare, is employed. However, if the spare combustor concept is not used, a standby fuel source is mandatory for continuous plant operation. It is likely that, because of logistical problems involved in obtaining large amounts of fuel on short notice, the standby fuel approach is not feasible.

Turndown Capabilities of the Combustor

The reported turndown capability of the process is 33:1, thereby providing no overall boiler system turndown restriction.

Safety Aspects of the Process

A number of potential safety hazards are inherent in the process, but none are considered insurmountable by various power plant management personnel.

The most significant potential hazard is the location of a large amount of molten iron at localized high temperatures within the boiler area and its potential for leakage from the com-

DISCUSSION (Continued)

Operational, Maintenance and Safety Aspects (Continued)

Safety Aspects of the Process (Continued)

bustor. This hazard can be reduced by use of steel production safety procedures for personnel protection and construction of dikes or similar features to contain the molten iron in the event of leakage from the combustor.

A second potential safety hazard is the possible introduction of water into the molten iron and the resulting high, instantaneous partial pressure created by high process temperatures. Two possible sources of water introduction are, as follows:

1. Large amounts of water resulting from boiler tube failure. This hazard can be reduced by proper design of the off-gas ducting to prevent water flow into the combustor.
2. Water-cooled lance failure, with potential release of water beneath the molten iron-slag interface. Power company representatives have expressed the opinion that, because of this extremely hazardous situation, some other means of lance cooling must be devised before power station application is feasible. Present ATC bench-scale operation uses water-cooled lances.

A third potential safety hazard is the explosive nature of the combustor off-gases. It is concluded that safety procedures comparable to those used in the handling of natural gas will be adequate to protect against this hazard.

DISCUSSION (Continued)

Operational, Maintenance and Safety Aspects (Continued)

Scheduled Maintenance and "Down-Time"

The gasification system can be designed to provide non-interruptible service by the use of a minimum of two combustor systems, with one system in operation at all times. The spare combustor may be refitted during its "down-time". Combustors should be periodically switched to the sparing operation to permit servicing. Minimum design service life for any component of the combustor system should be one year for operational and maintenance feasibility.

Design Problems

Listed below are a series of unresolved problems with respect to design of a workable installation incorporating the ATC Coal Gasification process:

1. The negligibility of particulate emissions from the process for commercial installations has not definitely been established. Significant emissions in a "retrofit" plant, because of possible scale build-up on the boiler tubes and possible resulting tube abrasion, could shorten boiler life. In addition, significant particulate emissions could require installation of an electrostatic precipitator or other cleanup device, not presently considered in existing cost data.
2. Expansion, manifolding and isolation of 20' - 30' diameter combustor off-gas ducts, or small ducts of equivalent cross-sectional area, represent a major design effort. Refractory

DISCUSSION (Continued)

Design Problems (Continued)

2. (Continued)

lining and/or water cooling are apparently mandatory.

3. No developmental work has been conducted to determine the type of refractory lining to be used in the combustors and ducting, sufficient to provide a minimum service life of one year.

4. The feasibility of transporting 2500°F - 2700°F process off-gas has not been determined. Associated ducting costs, or potential heat exchange requirements with boiler combustion air, may be a significant cost factor in a "retrofit" plant.

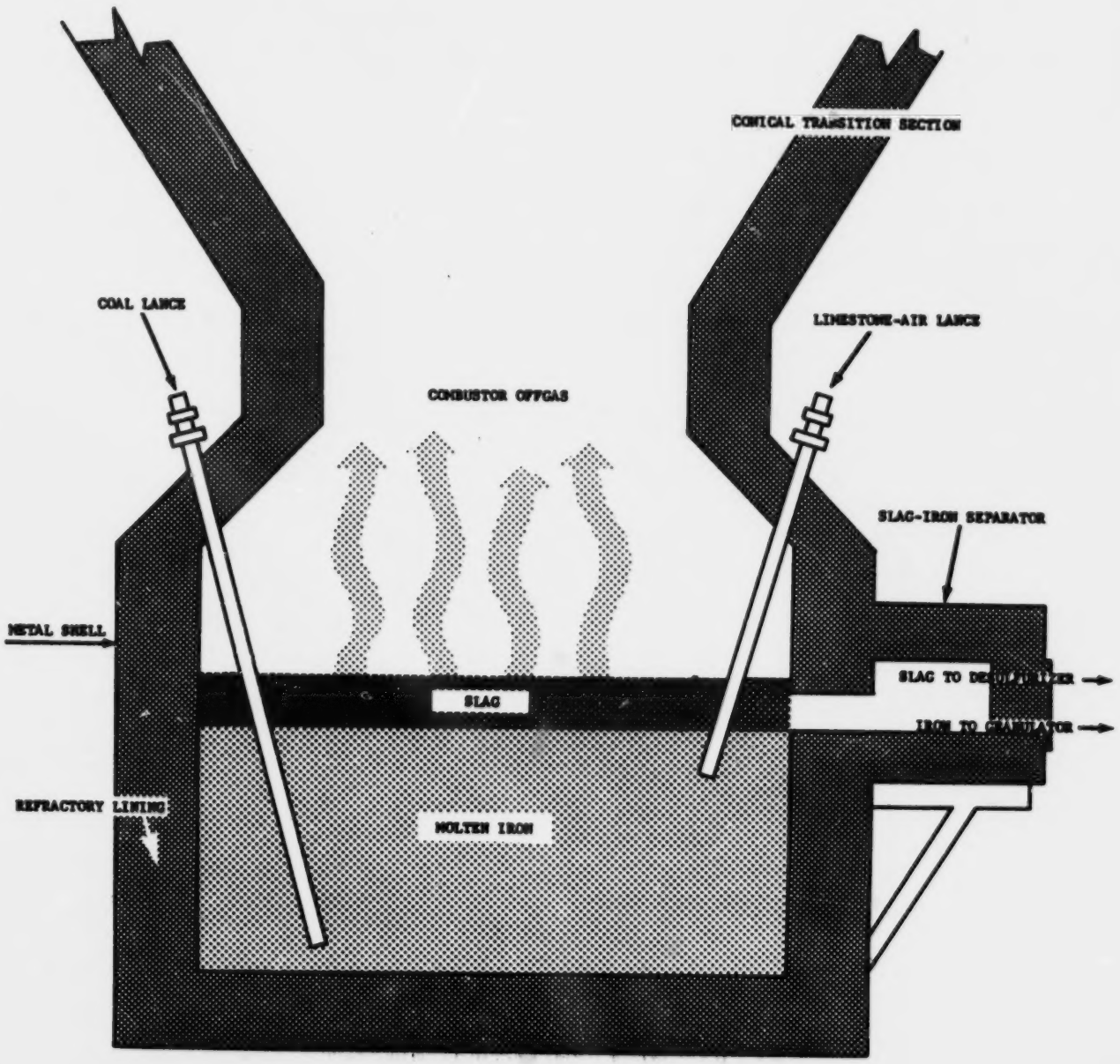
5. At present, no known design exists for a lance which will withstand the combustor service conditions. The present indication is that a lance cooled by liquid metal, oil or material other than water must be used. In addition, no information is available to relate the number of lances required as a function of combustor size.

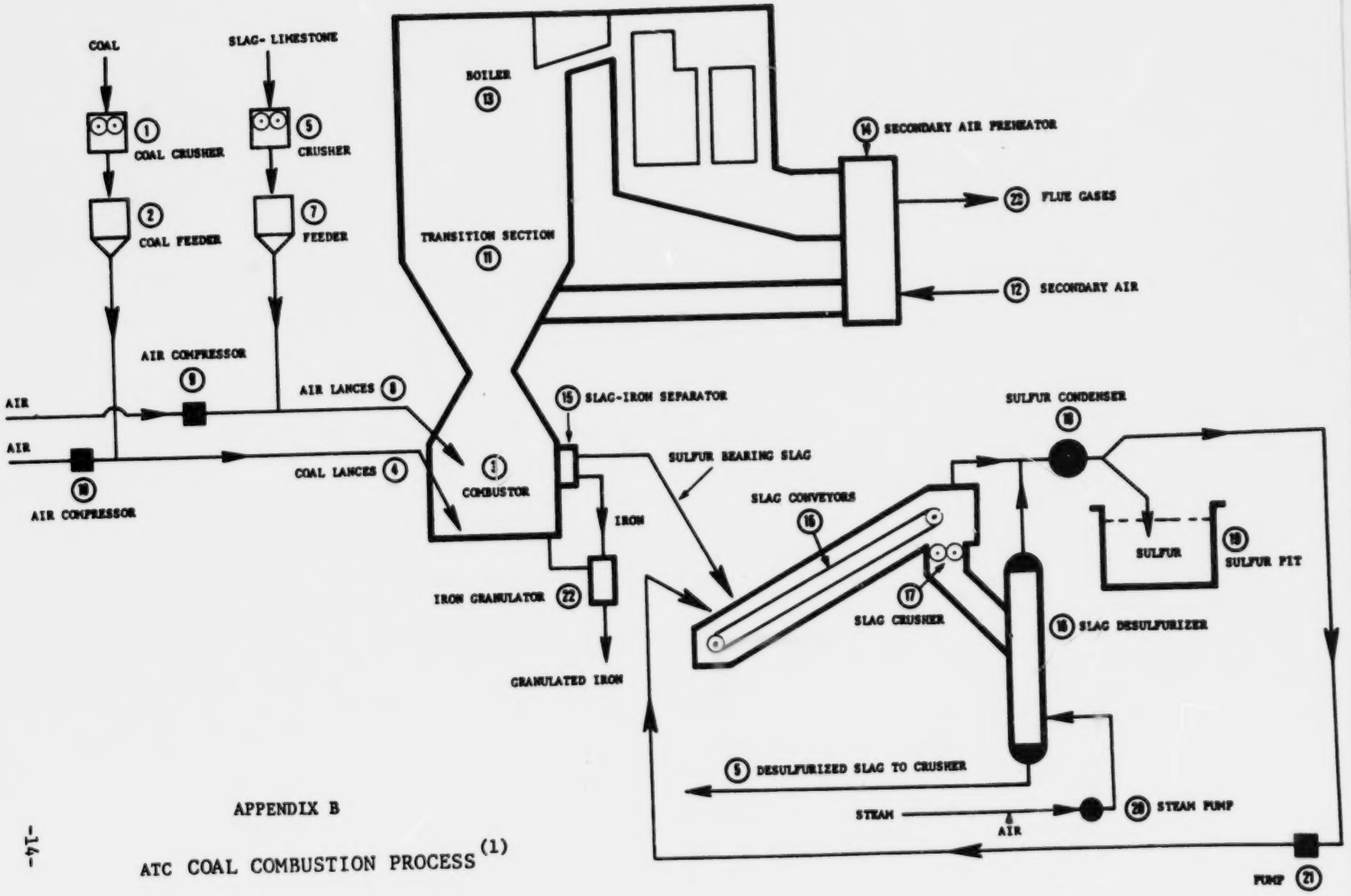
6. No information is presently available regarding either flame temperature or NO_x emissions from the combustion of the process off-gas. It is possible that significant amounts of NO_x may be formed if the pressure in the system must be raised to enable process off-gas flow to the boiler combustion chamber.

7. No data are presently available on the "weathering" effect of non-desulfurized slag. Long-term possibilities of this effect may be formation of hydrogen sulfide or leaching out of sulfuric and/or sulfurous acids.

APPENDIX A

CONCEPTUAL DESIGN OF COMBUSTOR ATC COAL COMBUSTION PROCESS[1]





APPENDIX B

ATC COAL COMBUSTION PROCESS[1]

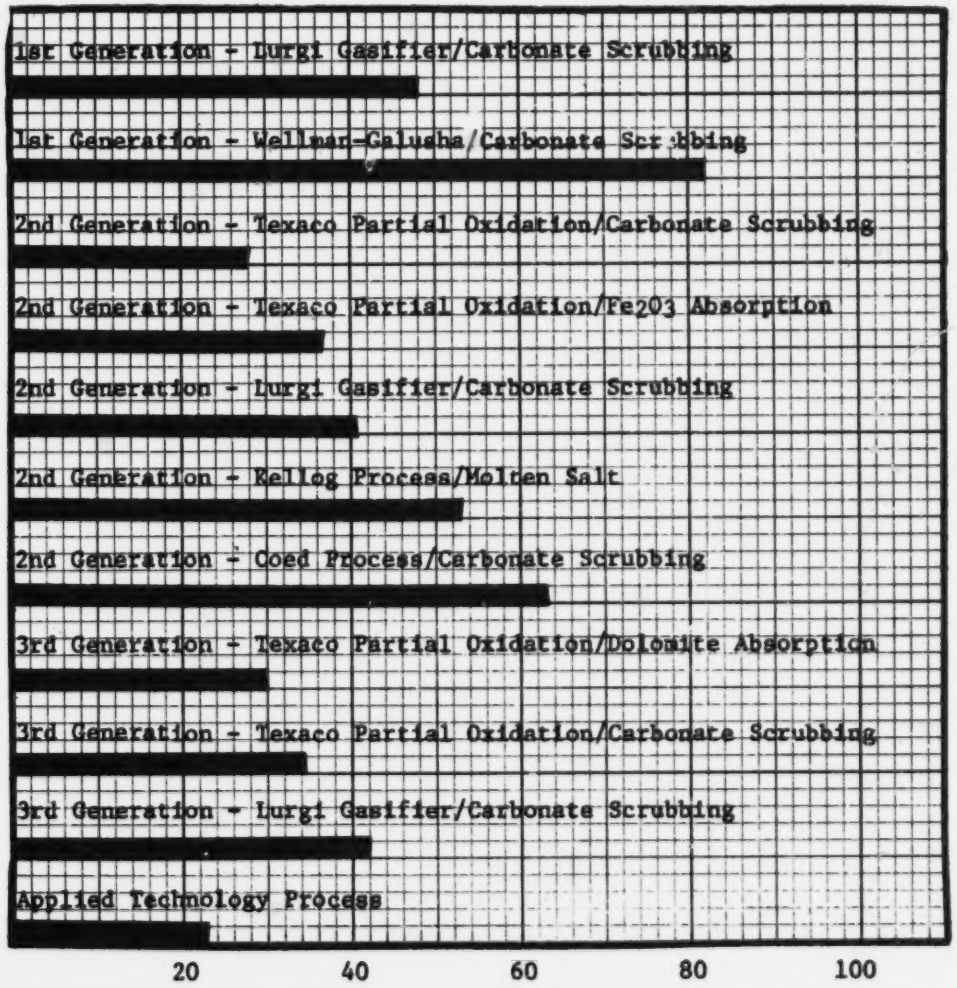
APPENDIX C

ESTIMATED FIXED CAPITAL REQUIREMENT
TWO-STAGE COAL COMBUSTION PROCESS
1000 MW POWER PLANT[1]

	EQUIPMENT COMPLEX	$MM
	Combustor	1.41
	Coal Preparation	2.25
	Flux/Slag Preparation	0.42
	Desulfurization	0.37
	Air Preparation	2.59
1.	Total Purchased Equipment Cost	7.04
	Installation, Piping, Electrical Instrumentation, Utilities (70% of 1)	4.92
2.	Physical Plant Costs	11.96
	Engineering and Construction (30% of 2)	3.59
3.	Direct Plant Cost	15.55
	Contingency (10% of 3)	1.56
	Contractor's Fee (6% of 3)	0.93
4.	TOTAL	18.04
	Escalation to 1980 (14.75% of 4)	2.66
5.	TOTAL	20.70
	Interest During Construction (12.6% of 5)	2.63
6.	TOTAL FIXED CAPITAL (1980)	23.33

APPENDIX D

Capital Costs for Coal Gasification/Sulfur Removal Processes

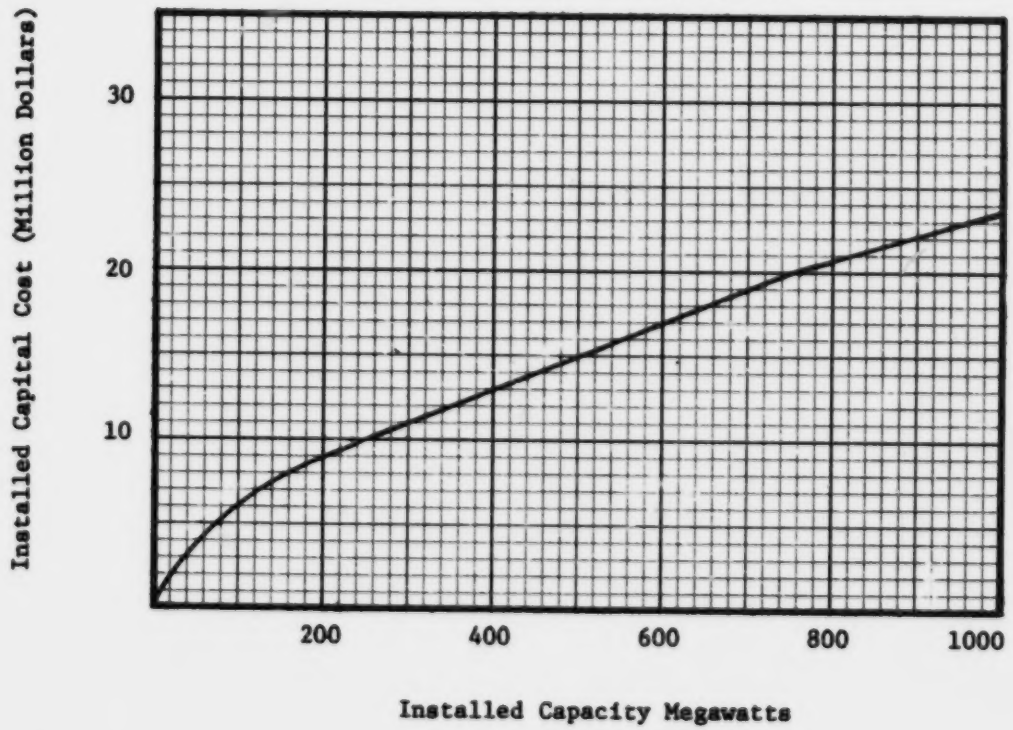

1st Generation - Lurgi Gasifier/Carbonate Scrubbing
1st Generation - Wellman-Galusha/Carbonate Scrubbing
2nd Generation - Texaco Partial Oxidation/Carbonate Scrubbing
2nd Generation - Texaco Partial Oxidation/Fe2O3 Absorption
2nd Generation - Lurgi Gasifier/Carbonate Scrubbing
2nd Generation - Kellog Process/Molten Salt
2nd Generation - Coed Process/Carbonate Scrubbing
3rd Generation - Texaco Partial Oxidation/Dolomite Absorption
3rd Generation - Texaco Partial Oxidation/Carbonate Scrubbing
3rd Generation - Lurgi Gasifier/Carbonate Scrubbing
Applied Technology Process
20
40
60
80
100
Fixed Capital Cost $/KW

Cost based on 1000 MW (nominal) plant

Appendix E

ATC Coal Gasification Process

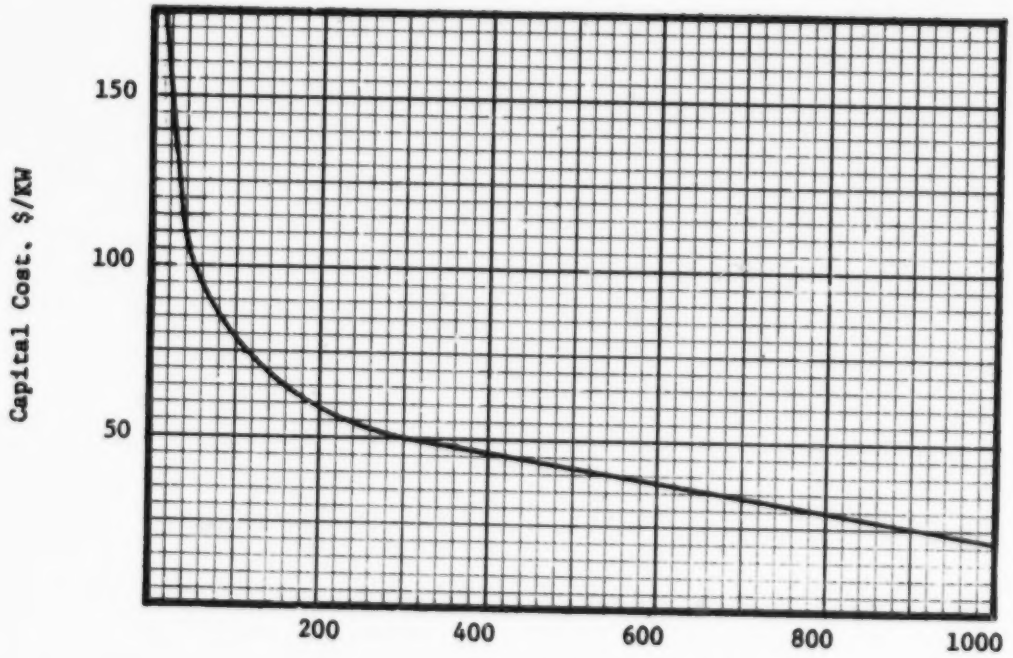
Installed Capacity vs. Capital Cost

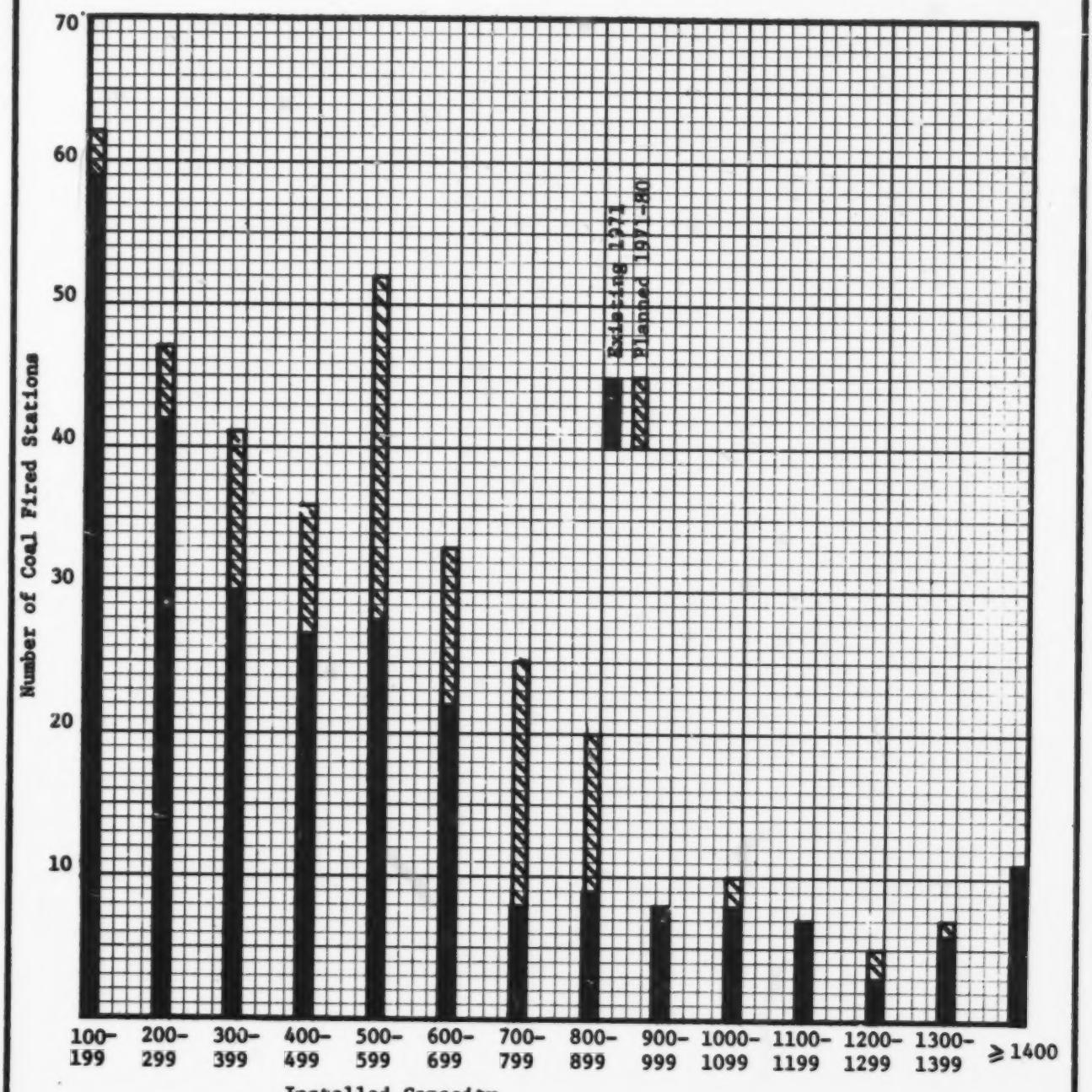


APPENDIX F

ATC Coal Gasification Process

Installed Capacity vs. Cost/KW





APPENDIX G

Existing and Planned Power Generating Facilities ≥ 100 MW

REFERENCES

(1) Pelczarski, E. A., P. LaRosa. Two Stage Combustion Process. Applied Technology Corporation. Table II. December 2, 1971

(2) Robson, F. L. et al. Technology and Economic Feasibility of Advanced Power Cycles and Methods of Producing Non-Polluting Fuels for Utility Power Stations. United Aircraft Research Laboratories. December 1970. 38-84 p.

(3) Ibid, 38-84 p.

(4) Rowe, W. D. The Mitre Corporation. December 1971.

(5) Cantrell, Ailleen. Annual Refinery Survey. Oil and Gas Journal. Volume 69, No. 12. March 22, 1971.